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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

RESPONSES OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) TO QUESTIONS POSED IN ORDER INSTITUTING RULEMAKING AND COMMENTS ADDRESSING SCOPE

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I. INTRODUCTION

The California Public Utilities Commission ("CPUC" or "Commission") issued an *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769* ("DRP OIR") on August 14, 2014. This rulemaking ("R.14-08-013") was opened to establish policies, procedures, and rules to guide California investor-owned electric utilities ("IOUs") in developing Distribution Resources Plan ("DRP") proposals to be filed by July 1, 2015, as required by Assembly Bill ("AB") 327, subsequently enacted, in part, as Public Utilities Code ("P.U. Code") §769. Pursuant to AB 327, the IOUs' DRPs must include methodologies to define locational benefits and optimal locations for Distributed Energy Resources ("DERs"), augmented or new tariffs and programs to support efficient DER deployment, and the removal of specific barriers to deployment of DERs. The Commission will consider incorporating additional spending necessary to integrate cost-effective distributed resources into its distributed energy plans for consideration in subsequent general rate case ("GRC") requests.[1] Accordingly, the DRP OIR will evaluate the IOUs' existing and future electric distribution infrastructure and planning

[1] Section 769 (d).

procedures as it pertains to incorporating DERs into the planning and operation of the utilities' electric distribution systems.

Among other things, the DRP OIR posed a number of specific questions and instructed the investor-owned utilities ("IOUs") to file answers to the questions and provide any comments as to the scope of the proceeding. San Diego Gas & Electric Company ("SDG&E") respectfully submits its comments and responses below. Per the Commission's instructions, the responses to each specific question are limited to one page. Thus, each response should be viewed as a summary or outline of issues to be more fully developed as the proceeding progresses.

II. SDG&E'S COMMENTS ADDRESSING THE SCOPE OF THE PROCEEDING

SDG&E believes the overarching goal of AB 327 and this proceeding is to facilitate integration of DERs at optimal locations by considering reliability, operational, and safety issues, as well as system costs and benefits from investments in DER. SDG&E also believes that such integration will fundamentally change the way the IOUs perform distribution planning. Accordingly, the scope of this proceeding should address the following issues:

- Presently, the IOUs plan distribution circuits from the substation outward, as would be expected in a central source to point load system. While there will always be a central source in the power system, the addition of point sources throughout the distribution system changes the distribution planning paradigm. SDG&E envisions that with the proper physical assurances, DERs may be able to play a role in capacity planning. DER systems, once properly analyzed and configured, may enable the deferment and in some cases the elimination of traditional capital distribution, capital transmission and/or utility-scale generation projects. This does not mean, however, that any and all traditional projects can be replaced by DER projects. It is important to identify the reliability services DERs may potentially provide, the reliability services that only the IOUs provide, and the appropriate regulatory oversight.
- Reliability based capacity services on the distribution system that a DER may potentially provide are straightforward: increasing the load carrying capability of a circuit/substation

through reliance on DER (i.e., serving the load locally may eliminate the need for additional circuit or substation capacity). Additional DER reliability services are not as straightforward. Reliability services on the distribution system that are reserved to the utility include system protection, system control, and service restoration. Utilities are best suited to detect and isolate distribution system faults, as well as restore the distribution system after an event. Utility-controlled devices such as Supervisory Control and Data Acquisition ("SCADA"), electronic relays, and service restorers make this possible. In addition, utilities are best positioned to identify equipment that has high failure rates (such as certain vintages of underground cable), and then replace them ahead of time to reduce the frequency of forced outages.

- To realize the benefits of DERs, the rules governing performance of DERs must be changed and the IOUs' existing retail rate structures must be modified. If DERs are to be compensated for deferring or eliminating traditional infrastructure projects, DERs must have physical performance requirements with appropriate penalty provisions for non-performance. To create economic incentives for DER performance, and to provide compatible consumption signals for end-use consumers, retail commodity rates need to be far more location-specific and time-differentiated than is currently the case. Additionally, the retail rates under which the utility's fixed costs are recovered should be more time-differentiated (i.e., a larger share of the utility's fixed costs should be recovered through demand charges based on end-users' maximum grid withdrawal during defined billing periods).
- In defining the reliability services that DERs can provide, SDG&E recommends that the Commission reference and incorporate existing and proposed standards for DERs such as UL 1741[2] and IEEE 1547.[3] In addition, the Commission should defer to utility

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[2] UL 1741 provides industry guidance regarding Inverters, Converters, Controllers and Interconnection System Equipment for use with DERs.
[3] IEEE 1547 is a standard of the Institute of Electrical and Electronics Engineers to provide criteria and requirements for the interconnection of distributed generation resources into the U.S. power grid.

experience in such areas as local area load forecasting, data gathering and analysis, automation, and protection schemes.

- As the Commission correctly identified in the DRP OIR,[4] P.U. Code § 353.5 already requires the utilities to consider DERs as part of the planning process. SDG&E has formalized processes to ensure compliance with this statute. The Commission should review and consider these documents when establishing criteria to guide the IOUs' development of the DRPs.
- SDG&E recommends that the Commission adopt, as quickly as possible, the smart inverter requirements to facilitate management of distribution-level voltage and power quality, thereby enhancing DER deployment at the lowest overall cost to consumers. Smart inverters will mitigate some of the challenges of DERs, therefore allowing more to connect.[5]
- It is important for the utilities to gain Commission support for timely installation of distribution upgrade projects or other distribution-level solutions that meet identified system needs. This will decrease the likelihood that overall system safety and reliability will suffer.[6]

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[4] Order Instituting Rulemaking (R). 14-08-013 at pages 2-3.
[5] PG&E, SCE and SDG&E filed a joint motion regarding the implementation of Smart Inverters on July 18, 2014, pursuant to Assigned Commissioner's Amended Scoping Memo and Ruling Requiring the IOUs to File Proposed Revised Electric Tariff Rule 21, dated May 13, 2014 in Rulemaking (R.) 11-09-011.
[6] D.03-02-068, pg. 17 "The key utility responsibility is system planning. System planning must consider distributed generation alternatives (both on the grid side and customer side of the meter) to wires upgrades as part of the normal planning process. Non-utility solutions should be actively solicited through the planning process. The level of utility control/physical assurance should be weighed in evaluating/selecting options. We do not wish to re-create a BRPU-type process for determining whether wires or distributed generation should be used to satisfy demand for electricity in distribution constrained areas. As part of each utility's planning process, each utility shall determine when a distribution system upgrade is necessary to ensure reliability and safe operation of the system. As a part of this determination, the utilities shall determine if a grid-side distributed generation unit could be a reasonable means of providing the electricity demanded in the identified constrained area."

III. RESPONSES TO QUESTIONS

1. What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?

SDG&E recommends that development of the IOUs' DRPs be guided by the following criteria:

- Since the utility has ultimate legal responsibility to provide reliable service to customers, it must have the right to control any DER that chooses to be compensated for providing reliability services. [7]
- Reliability services provided by a DER must be defined, measurable and meet performance thresholds.
- The utility will continue to be responsible for providing the reliability services that are needed, but that are not met by DERs that agree to provide such services.
- The costs the utility incurs to provide reliable service to customers, including the payments made to DERs that provide reliability services, are fully reflected in rates.
- Rates charged by the utility to customers, including DER customers, are structured so that each customer bears its fair share of the costs incurred by the utility to provide reliable service to that customer.

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[7] Pub. Util. Code §399.2(1)(2)- "…each electrical corporation shall continue to operate its electric distribution grid in its service territory and shall do so in a safe, reliable, efficient, and cost-effective manner". Each utility is "responsible for operating its own electric distribution grid, including . . . owning, controlling, operating, managing, maintaining, planning, engineering, designing, and constructing its own electric distribution grid."

2. What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

In order to comply with the statutory requirements of AB 327, the DRP should include the following:

- Evaluation of locational benefits and costs of distributed resources located on the distribution system. This evaluation should be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, and any other savings the distributed resources may provide to the electric grid or costs to IOU ratepayers. These types of benefits are directly measureable in that the dependable capacity of the DER can be determined, and the deferred or avoided distribution and transmission upgrades can be identified in advance.
- Mechanisms (e.g., standard tariffs, Commission approved contracts, or other mechanisms) for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
- Methods to cost effectively coordinate existing Commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
- Additional utility spending forecasts necessary from General Rate Case filings to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

3. What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

To properly identify optimal locations, several factors must be evaluated, including feeder length, distribution of load along the feeder, hourly load profile, feeder capacity, voltage profile, distance from the substation bus, DER locations along the feeder, and DER penetration level. All these factors are important when identifying optimal locations.

To provide locational benefits, the DER must meet these four requirements: (1) it must be installed in the right location, (2) at the right time to avoid utility distribution and/or transmission upgrades, (3) of the right size to meet the capacity need, and (4) provide physical assurance or a guarantee of performance to ensure the resource needs are met.

An optimal location would be one which provides one or more of the system enhancements mentioned above, requires little to no system upgrades, reduces local capacity requirements, and potentially increases the life cycle of distribution equipment by reducing loading on the equipment. This is optimal because it avoids incremental costs associated with a DER project. Indeed, the goal of DER integration should be to avoid doing the very same upgrades the utility would have done anyway - just to accommodate a DER project. Thus, an effective DER integration strategy would identify those locations where DERs/DG can fit seamlessly into the system without the need for significant upgrades. This may be done via exhaustive locational analyses, resulting in specific installation sites, or via high-level "optimization zones," which would identify broader areas where DERs would have a greater chance of success[8]. The identification and labelling of these "optimization zones" would be general in nature, and would not ensure that every project would find an optimized location.

In addition, the utility may choose to perform some system enhancements in targeted areas in hopes of attracting DER resources. This would be done to meet reliability needs through a combination of utility investment and DER installations. The hope is that a minimal infrastructure upgrade in conjunction with the appropriate resource request for proposal would meet identified distribution system needs that would normally require a much larger traditional infrastructure project. Given the unique characteristics of each location, the optimization should result in deployment of a DER technology that meets those specific needs. However, the choice of technology would likely not be the same in all locations.

[8] It should be noted that the IOUs already provide this information to developers.

4. What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

There are two distinct concepts of value that should be considered in the development of a locational value. One is transmission or system-oriented support, and the other is distribution focused. The California Independent System Operator ("CAISO") manages markets for system benefits, such as energy and ancillary service capacity. At the transmission level, the CAISO manages the system voltage profile through the use of capacitors, static VAr compensators ("SVCs"), synchronous condensers and other voltage control devices. In addition, the CAISO can require generators to provide voltage regulation within a pre-defined lagging and leading power factor range. At present, the CAISO does not have a market that compensates generators for the reactive power they may be dispatched to provide or absorb. Rather, each generator is obligated to provide voltage control within the pre-defined range as a condition of market participation.

SDG&E recommends that the Commission adopt a similar principle for DER-supplied voltage control at the distribution level. DERs that wish to be compensated for the reliability services they provide would be obligated to provide voltage control within a pre-defined power factor range as a condition of eligibility for such compensation. This is consistent with the IOUs' joint motion regarding the implementation of Smart Inverters (filed on July 18, 2014), pursuant to Assigned Commissioner's Amended Scoping Memo and Ruling Requiring the IOUs to File Proposed Revised Electric Tariff Rule 21, dated May 13, 2014, in R.11-09-011. Smart inverters - which SDG&E would have the right to control under the DRP criteria set forth in response to question 1 - provide local voltage control capability for DERs that would otherwise lack such capability.

The CPUC provides a mechanism by which load serving entities meet their local and system RA requirements. At present, there is no rate mechanism in place for compensating DERs for distribution system benefits, although SDG&E has a Commission approved form contract that allows SDG&E to compensate third parties for identified capacity deferral benefits. That said, SDG&E believes that utilities should be compensated for the services the utility provides to customers, and that DERs should be compensated for the services provided by DERs. Rate reform is essential to ensure this is accomplished.

5. What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

As noted above, SDG&E has already implemented processes to incorporate DERs into the planning process and Commission-approved form contracts for compensating third parties for allowing SDG&E to defer capital infrastructure upgrades. SDG&E has also performed tests of its procedures by designating an interconnection point if a third party installed a DER in accordance with the Commission-approved requirements.[9] To appropriately integrate DERs into planning and operations, it is necessary to properly model the behavior of each DER class, specifically identifying the performance metrics of Photovoltaic ("PV"), storage, and other DERs. IOUs must have assurances of availability if they are to incorporate DERs into their forecasting and planning methodology. For operational concerns, inverter based DERs with smart inverters should be incorporated into Voltage Optimization ("VAr") and Distributed Energy Resource Management System ("DERMS") schemes where feasible. DERs will also be required to have anti-islanding schemes per Rule 21 to ensure the safety of IOU personnel. To track performance and ensure safety, a monitoring and/or control device should be installed at each DER device for data retrieval and operability.

[9] D.03-02-068, pg. 18 "SDG&E outlines the criteria distributed generation must meet to allow the utility to defer capacity additions and avoid future cost. The distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth. The unit must be installed and operational in time for the utility to avoid or delay expansion or modification. Distributed generation must provide sufficient capacity to accommodate SDG&E's planning needs. Finally, distributed generation must provide appropriate physical assurance to ensure a real load reduction on the facilities where expansion is deferred. There is potential that distributed generation installed to serve an onsite use will also provide some distribution system benefit, however, unless it meets the four planning criteria describe [sic] by SDG&E, such benefits will be incidental in nature."

6. What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

Unlike the IOUs, DERs have no legal obligation to serve load or to restore power following an outage. The reliability services a DER may provide are therefore limited to the capacity deferral or elimination of traditional utility infrastructure projects. As described above, utilities will continue to provide the other reliability services. SDG&E believes that utilities should be compensated for the services they provide to customers and DERs should be compensated by customers for services provided by DERs. Rate reform is essential to ensure this occurs. If DERs are willing to provide reliability services, then an appropriate mechanism will be required to value those services. Allowing DERs to provide reliability services must be carefully evaluated to determine the level of regulatory oversight that might be needed

7. What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

DERs can potentially provide benefits to the distribution system, including voltage and VAr support, peak shaving, and resource smoothing. However, sufficient assurance of the availability of the DER must exist in order for the DER to displace other capacity or reliability investments.

8. What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

SDG&E believes that the More Than Smart ("MTS") effort mentioned in the response to Question 16 is the appropriate place to develop guidelines and scenarios to test integration strategies. For example, the four grid end states identified in the MTS paper represent the scenarios that should frame the analysis done for DER integration. Criteria that should be considered are laid out above and in the MTS paper and include deferred investment, improved power quality and reliability, network access, and system operability. At no point should the integration of DER degrade the utility's ability to maintain and operate the distribution system. Inputs to the scenario development can include EV adoption rates, DER penetration rates, DER management schemes, and redesigned rate structures among others. The scenarios themselves will play a significant role in the criteria and inputs chosen.

9. What types of data and level of data access should be considered as part of the DRP?

Data access and the types of data made available to third parties is a pertinent issue for all aspects of the distribution planning process and rulemaking. The DRP should address planning, engineering, and operational data that third parties may need to provide to utilities for effective, reliable integration of DERs. To facilitate DER deployment, SDG&E has developed a web-based process to identify available capacity on its circuits and substations. The Commission should review third-party use of this web-based process to ensure that this valuable resource is being utilized.

Discussion of data issues among parties should also address any data that may be made available to or from third parties which could be confidential or proprietary utility planning, engineering, and/or operational data, including customer-specific data which may already be covered under existing statutes or Commission decisions. In particular, the Commission recently addressed third-party access in D.14-05-016, including a process for requesting data and the types of data available to third parties. This decision was the result of several months of workshops, including input from privacy experts, IOUs, and interested third parties. To the extent these issues have already been addressed in other venues, SDG&E does not recommend the Commission re-litigate those issues in this proceeding.

10. Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

As discussed above, P.U. Code § 353.5 already requires utilities to evaluate DER alternatives. SDG&E has procedures in place and compares DERs against capital project upgrades. Accordingly, utilities and third parties should leverage data collected from existing DER projects, including pilots and demonstrations (for example, SDG&E's Borrego Springs Microgrid demonstration project) to help inform the DER planning processes.

11. What considerations should the commission take into account when defining how the DRPs should be monitored over time?

SDG&E recommends a vetting of its DRPs in periodic public workshops, and the Commission should consider whether and how to have meaningful, non-duplicative updates or reporting that will improve the DER planning process and provide useful feedback to stakeholders.

12. What principles should the commission consider in setting criteria to govern the review and approval of the DRPS?

The Commission should conduct a compliance review as to whether the IOUs have met the known statutory and Commission requirements for DRPs and approve the DRPs if those requirements have reasonably been met. Reasonableness reviews based on new facts, rules or laws unknown at the time the DRPs are issued should be prohibited.

13. Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

As discussed in response to Question 5, the Commission has already determined the criteria under which DERs can provide value. The ability of DERs to provide reliability benefits is impeded by today's rate design. It is also contingent on the third-party DER willing to abide by guidelines which make it available when needed. Any discussions on new ownership models must carefully consider the implications of a new paradigm and ensure that commiserate responsibilities are put on the appropriate party and enforcement mechanisms which extend beyond the IOU are in place. Without these, the safety and reliability of the distribution system are at risk.

14. What specific concerns around safety should be addressed in the DRPs?

DERs must meet all applicable federal, state, and local safety requirements for interconnection with utility distribution systems. In addition, inverter based DERs must adhere to the specifications in section Hh of the revised Rule 21 as developed by the Smart Inverter working group (anti-islanding, etc.). There also needs to be visibility by the IOU as to DER status at any given time.

SDG&E's Average System Availability Index ("ASAI") has been approximately 99.99% for the last 10 years, which means that SDG&E customers have electric service 99.99% of the time - a very high level in the industry. This level of reliability represents a significant investment by SDG&E in the safety and reliability of its electric system. If DERs failed to perform the intended function upon which utilities rely, then safety is put at risk. Operational impacts and benefits of DERs have been studied and reported on previously.[10]

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[10] California Public Utilities Commission Order Instituting Rulemaking into Distributed Generation R. 99-10-025, Distribution System Operations and Planning Workshop Report April 17, 2000.

15. What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

None, other than what is provided in response to these questions and in Section II above regarding the scope of this proceeding. Further actions may be identified as the proceeding progresses.

16. Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

a. **Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?**
b. **Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?**
c. **Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?**
d. **Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?**
e. **Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?**
f. **Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?**

SDG&E has provided input to the More Than Smart ("MTS") working group, and as such, has played a part in the creation of the white paper attached to this OIR. As part of its involvement, SDG&E is helping to shape the scenarios for the Integrated Grid Framework, as well as the Integrated Grid Roadmap. In addition, SDG&E continues to guide the MTS effort in regards to Planning, Design, and Operational concerns. SDG&E will continue to be involved in this working group and plans to utilize the output of the group in its DRP.

IV. CONCLUSION

SDG&E appreciates the Commission's effort reflected in this DRP OIR to provide guidance as to how the utilities should develop their DRPs. SDG&E also appreciates the opportunity to comment on the scope of the proceeding, including the key criteria upon which DRPs will be evaluated. As reflected in the foregoing comments, SDG&E intends to develop a DRP that facilitates integration of DER at optimal locations in a manner that minimizes overall system costs and maximizes ratepayer benefit from investments in DER, while at the same time maintaining system safety and reliability. SDG&E understands that this goal will require great effort and that there is much to be done in a relatively short amount of time, since the DRPs are to be submitted by July 1, 2015 (approximately five months after the Commission is scheduled to issue its DRP guidance in this proceeding). Accordingly, SDG&E encourages a strong focus on the foundational aspects of DER integration. Without this strong focus, there is a risk that the proceeding will fail to provide the basic rules and policies required to develop the DRPs mandated by P.U. Code §769.

DATED at San Diego, California, this 5th day of September, 2014.

Respectfully submitted,

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